EnergyNorway

Your reference	Our reference	Date
	DM-308213	9 November 2010

ERGEG
28 rue le Titien
1000 Brussels

Energy Norway response to the ERGEG consultation on the Framework guidelines on Capacity Calculation and Congestion Management for Electricity

Energy Norway welcomes the opportunity to comment on ERGEG’s draft Framework guidelines on Capacity Calculation and Congestion Management for Electricity. The framework guideline addresses important issues in a well structured manner and can be developed into a good guidance for the following network codes.

Energy Norway is a trade organisation for about 260 generators, suppliers, distributors and contractors in Norway. Energy Norway's members each year produce nearly 130 TWh, which is some 99 per cent of all power production in Norway. Our members have approximately 2.5 million grid customers, which is about 91 per cent of Norway`s grid customers. The members of Energy Norway have some 15 000 employees, and had a gross turnover to end-users in 2009 of 75-80 billion Norwegian kroner.

General Issues

1. Are there any additional issues and / or objectives that should be addressed in the Capacity Allocation and Congestion Management IIA and FG?

While being quite comprehensive on the role of TSOs and NRAs the guideline currently lacks a more thorough description of ACER’s role. As for instance intermediate steps towards target models, the definition of price zones or handling of cross border capacity might be managed in different ways by the various TSOs and NRAs, the guideline would benefit from giving a clear role to ACER to coordinate the NRAs and ensure a common European interpretation of the guideline’s aims and targets to facilitate harmonisation.

Energy Norway P.O Box 7184 Majorstuen, N-0307 Oslo Tel: +47 23 08 89 00 Fax: +47 23 08 89 01
E-mail: post@energinorge.no www.energynorway.no

Another issue that should be explicitly addressed in this guideline is the compatibility of this FG with the upcoming guidelines on fundamental data transparency, balancing and day-ahead governance. To ensure transparency and consistency in the interaction between them, the other guidelines should be explicitly addressed in the relevant provisions of this FG.

2. Is the vision of the enduring EU-wide target model transparently established in the IIA and FG and well suited to address all the issues and objectives of the CACM?

The FG would benefit from describing the vision and target models in more detail to ensure a harmonized interpretation in Europe and offer clear guidance to the TSOs for the future code development process.

3. Should any of the timeframes (forward, day-ahead, intraday) be addressed in more detail?

See question 2.

4. In general, is the definition of interim steps in the framework guideline appropriate?

Given the different starting points, interim steps towards the enduring targets might be necessary, but a definition of the different interim solutions might be difficult because of that. In Energy Norway's view, it is more important to develop common criteria to assess interim steps to ensure their compatibility with the target models. These criteria should be mentioned in the FG. ACER should be given a role to assess whether an interim step is necessary and, if yes, whether it is meeting the criteria. One criterion should be that the interim model has to facilitate the way towards the target and not become an obstacle in the implementation of the enduring solution. Other criteria can be transparency and the existence of a clear road map towards the target model.

5. Is the characterization of force majeure sufficient? Should there be separate definitions for DC and AC interconnectors?

The FG would benefit from a more detailed definition of force majeure, which should be the same for AC and DC interconnectors. More details can help to ensure a common European interpretation and prevent differences of opinion. ACER should have a surveillance role.

6. Do you agree with the definition of firmness for explicit and implicitly allocated capacity as set out in the framework guideline? How prescriptive should the framework guideline be with regard to the firmness of capacity?

In Energy Norway's view, firmness should be defined in more depth in the guideline, either in a provision in the chapter linked to each time frame or in a separate chapter. The definition should include compensation rules for capacity holders in case the capacity is constrained. In our view, the guarantee of financial firmness is sufficient, as it might be impossible to implement physical firmness in case of an interrupted line due to force majeure.

In general, Energy Norway wants to underline that the timely publication of volumes of available capacity for each timeframe is important. This should be done for each connection between bidding areas. The transparency provisions should be compatible with or make a reference to the transparency guideline.

7. Which costs and benefits do you see from introducing the proposed framework for Capacity Allocation and Congestion Management? Please provide qualitative and if applicable also quantitative evidence.

Overall the effects of the guideline will be very positive, as it will facilitate market integration and lead to a more efficient use of resources, which is essential for the integration of growing amounts of intermittent renewables.

While the overall effect of the guideline is likely to be beneficial, the guideline should contain more guidance on transparent cost assessment, where it is relevant. This concerns especially the provisions on capacity allocation methods, the potential change to flow based calculation and the provisions on zone delineation. More details can be found in question 8 and in question 13.

Section 1.1: Capacity calculation

With regards to provision 1.1.1. “locational information”, Energy Norway would ask for additional clarification. Taking into account the growing need for flexibility due to increasing share of renewables, leading to more short term adjustments of production planning and production, detailed production information might be difficult to obtain in advance. In general the guideline should refer to provisions in the fundamental data transparency guideline to avoid duplication and keep consistency.

8. Is flow based allocation, as set out in the framework guideline, the appropriate target model? How should less meshed systems be accommodated?

Until now flow based calculation (FB) for an entire area is mainly a theoretical concept. Therefore prior to its eventual introduction, there needs to be enough time for transparent cost – benefit calculations involving stakeholders. If major costs such as for example reductions of available cross border capacities are discovered, alternatives such as coordinated ATC in combination with relevant zone delineations should be accepted. Defining the correct zones following structural congestions is a good step towards the efficient use of the grid, as structural constraints will be in that way automatically included in the price calculation process.

Energy Norway welcomes that coordinated ATC is confirmed as an alternative for the Nordic region and other less meshed networks, and encourages further work on this model to optimize its functioning.

9. Is it appropriate to use an ATC approach for DC connected systems, islands and less meshed areas?

Coordinated ATC is appropriate.

10. Is it necessary to describe in more details how to deal with flow-based and ATC approach within one control area (e.g. if TSO has flow-based capacity calculation towards some neighbouring TSOs and ATC based to the others)?

The FG should give the TSOs more guidance concerning the criteria to assess these situations such as neutrality, non-discrimination between borders, transparency etc. NRAs and in addition ACER should have a controlling role to ensure harmonized interpretation of the FG and the criteria.

11. Is it important to re-calculate available capacity intraday? If so, on what basis should intraday capacity be recalculated?

In general, the day-ahead market coupling process should be allocated the maximum available capacity to ensure efficient price formation. However, if there is free capacity after the day ahead market coupling, due to for example changes in intermittent generation or other unforeseen events, the utilization of that capacity should be maximized. Energy Norway agrees with provision 1.1.8. and asks for the coordination and evaluation of existing recalculation practices in Europe.

Section 1.2: Zone delineation

12. Is the target model of defining bidding zones on the basis of network topology appropriate to meet the objectives?

Energy Norway and our members have extensive experience dealing with the Norwegian market mechanism of zonal pricing. In principle, we agree that zones can contribute to correct price signals and efficient and transparent dealing with congestions, provided these zones are correctly delineated, introduced with enough advance notice and represent the actual physical constraints in the system.

The current draft FG would benefit from a clearer definitions of zones. Zones should not only be bidding zones, as mentioned in the draft, but also price zones. If consumers face a different price than producers, consumption patterns won't be adjusted and major part of the intended effect of zone delineation would be lost.

13. What further criteria are important in determining the delineation of zones, beyond those elaborated in the IIA and FG?

As the introduction of zones causes costs to market actors and can reduce grid investment incentives, clearly defined criteria are of paramount importance. Energy Norway would welcome a more detailed definition of criteria determining the delineation of zones and suggests additional ones. In our view it is important that the physical constraints in the system are reflected as accurate as possible without causing adverse effects on competition.

Structural congestion, mentioned in 1.2.4., should be the main criterion and as such defined in more detail. Not all congestions are necessarily of a structural nature i.e. causing a long term imbalance of supply and demand in a given area. Congestions that are caused by short term events (such as extreme cold/hot temperatures, low precipitation, failures in the transmission networks or large generation facilities) or maintenance should not justify the introduction of a new zone. Choosing structural congestion and the actual physical constraints as the main criterion also implies, that zones should not follow national borders, if those are not congested.

If structural congestion is identified as such, the best remedy would be grid investments. If the introduction of a zone is considered as an alternative, it should be preceded by a transparent assessment of the costs and benefits. Furthermore, investment incentives for new capacity should be given through the mechanism.

To assess whether the introduction of zonal pricing is beneficial, the FG mentions the cost of countertrade and redispatch as a criterion (1.2.4.). These costs should be made public to allow an open assessment. Ideally transparency on countertrade/redispatch should be part of the requirements in the comitology guideline on fundamental data transparency to ensure consistency.

Countertrade/redispatch cost for TSOs need to be compared with the effects on welfare (1.2.4.). Energy Norway thinks that the FG should offer more guidance with regards to the definition of welfare to consider both short and long term effects on the electricity markets and on investments.

To ensure a well functioning electricity market, the *size of the proposed new bidding and price zone* should be an important criterion. Energy Norway advocates as big zones as possible to keep the market functioning efficiently. Smaller zones have less market players, which reduces liquidity and increases the risk of market power within the small zone. Energy Norway disagrees, that creation of a liquid hub made up of several zones, as suggested in the IIA, would work as a remedy. Producers are still exposed to the zonal prices and to hedge them liquidity in each single zone is necessary. In addition, differences between the hub price and the price areas might become considerable due to the preexisting structural congestion, further reducing the value of the hub price.

Stability of the zone delineation should be another criterion: changing zones introduces uncertainty in the markets, which impacts liquidity. As old price hedging products might no longer function and new products are not necessarily introduced simultaneously with the creation of the new zones, market players lose hedging opportunities, which again impacts market liquidity as market players have to reduce risk exposure. If zones change too often, the uncertainty can become permanent, reduce trust in the market and damage it.

In the long term, changing zones and/or small size of zones might also impact on investment decisions of producers and large consumers. If electricity prices are no longer relatively predictable and/or comparable due to price zone uncertainty, investment might be reduced or financing cost might be higher.

Therefore, in Energy Norway's view, zones should not be introduced on an ad-hoc basis or after a short notice, as this exacerbates the problems linked to uncertainty. Long advance notice helps on the contrary market participants to adjust their positions and increases the credibility in the stability of the zone delineation. To discuss costs and benefits of potential new and existing zones, the guideline suggests an assessment once a year by the responsible NRAs (1.2.6), which Energy Norway welcomes. As zone definitions in one country might well influence the market in neighbouring countries and as cross-border zones might develop, ACER as the European regulator should receive a coordination and surveillance responsibility. Also stakeholders should be consulted in this process.

Section 2: Forward markets

14. Are the preferred long-term capacity products as defined in the framework guideline suitable and feasible for the forward market timeframe?

Energy Norway thinks that in the long term the market should evolve away from PTRs towards FTRs, as all available capacity should be used in the market coupling process to increase its efficiency. Other financial products, such as the CfDs currently used in the Nordics, can be additional options, if they are functioning equally well to hedge area price differences. This needs to be assessed in an open manner.

15. Is there a need to describe in more detail the elaborated options for the organisation of the long-term capacity allocation and congestion management?

Energy Norway welcomes that the NRAs should review and approve the levels of capacity offered by the TSOs (3.5.). In our view, ACER should also have a role in this review process.

Energy Norway disagrees with the view stated in provision 3.6. that the TSOs should set up a platform on secondary trading of capacity rights. In our view, trading of long term capacity rights is not closely linked to the operation of the power system such as day ahead and as such a trading platform for long term capacity rights can well be operated by power exchange(s).

Section 3: Day Ahead allocation

16. Are there any further issues to be addressed in relation to the target model and the elaborated approach for the day-ahead allocation?

Energy Norway welcomes that the day ahead target model has been defined as implicit auctions performed by one single algorithm in one calculation and that reference is made to the upcoming governance provision in the governance framework.

Section 4: Intraday allocation

17. Are there any further issues to be addressed in relation to the target model and the elaborated approach for the intraday allocation?

Energy Norway supports the introduction of an intraday solution that meets the requirements of the PCG target model, meaning the introduction of continuous implicit trading with an option for market based allocation only if significant additional capacity becomes available. The present draft FG is unfortunately not fully compatible with the PCG target model and should be adjusted to meet that agreed model.

As only the remaining capacity not used in the day ahead market coupling is open to intraday trading, the amounts concerned will be relatively small as a rule. These small amounts can be best allocated using continuous implicit trading to allow maximum flexibility. If due to some unforeseen event, significant new capacity becomes available to the TSOs, it should be allocated using a market based mechanism. The guideline would benefit from a definition of "significant additional capacity", to ensure a common European interpretation of this threshold.

In all cases the intraday solution chosen should be compatible with the introduction of cross border balancing trading and not preclude any decisions to be taken in the upcoming guideline on balancing markets.

18. Does the intraday target model provide sufficient trading flexibility close to real time to accommodate intermittent generation?

If a common continuous implicit trading solution is introduced in the whole European market, the market will be able to offer the necessary flexibility to integrate intermittent renewables. However, the integration of the different cross border intraday markets will take time due to the different starting points. Therefore changes to the PCG model introducing complexity and risk should be carefully assessed, as they could lead to a reduction of liquidity.

Cross border integration of balancing markets and in the long term investment in grid will have to meet additional flexibility needs.